RP 602 Wind Energy Power Plant Substation and Transmission Line Maintenance

The following recommended practice (RP) is subject to the disclaimer at the front of this manual. It is important that users read the disclaimer before considering adoption of any portion of this recommended practice.

This recommended practice was prepared by a committee of the AWEA Operations and Maintenance (O&M) Committee.

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Purpose and Scope

The scope of "Wind Energy Power Plant Substation and Transmission Line Maintenance" addresses the maintenance of wind farm electrical substation components, including area substations, the final connection to the grid, and their interconnecting transmission line. This document is not intended to be an all-inclusive how-to manual but to provide general guidance to sound maintenance practices and references to applicable industry standards.

Introduction

Electrical power equipment and systems testing should be performed as specified by manufacturer's standards from organizations such as IEEE, IEC, ICEA, or NFPA 70B. A summary of some of the applicable standards can be found in NETA standards. In most cases, the testing organization should be an independent, third party entity which can function as an unbiased testing authority and is professionally independent of the manufacturers, suppliers, and installers of equipment or systems being evaluated. The organization and its technicians should be regularly engaged in the testing of electrical equipment devices, installations, and systems. An example of one such organization which has an accreditation program is the InterNational Electrical Testing Association (NETA).

Introduction
(continued)

The testing organization should submit appropriate documentation to demonstrate that it satisfactorily complies with these requirements. The testing organization should provide the following:

- All field technical services, tooling, equipment, instrumentation, and technical supervision to perform such tests and inspections
- Specific power requirements for test equipment
- Notification to the owner's representative prior to commencement of any testing
- A timely notification of any system, material, or workmanship that is found deficient based on the results of the acceptance tests
- A written record of all tests and a final report

Safety and precaution practices should be in accordance with NFPA 70E and other applicable standards including IEEE standards.

Substation Maintenance

1. Main Power Transformer

The main power transformer should be tested completely before energization. Commissioning documentation should include information included in following testing and energizing procedure.

1.1. Test Oil Dielectric from Bottom Drain Valve

Should be 40 kV or higher.

1.2. Insulation Power Factor and Capacitance to Ground

Make the following test with a suitable power factor bridge. Measure only the power factor and capacitance on winding connections. Be sure to record the temperature of the insulation as accurately as possible. The temperature corrected values should not exceed 0.5%.

- Two winding transformers: HV to GRD with LV winding grounded (H-LG)
- LV-GRD. With HV winding grounded L-HG. HV connected to LV to GRD (HL-G)
- Autotransformers with tertiary winding: HV and LV to GRD with TV grounded (HL-TG)
- Autotransformers without tertiary windings: HV and LV to FRD (HL-G)

1.2. Insulation Power Factor and Capacitance to Ground
(continued)

- Three winding transformers:
    - HV to ground with LV and TV grounded (H-LTG)
    - LV to ground with HV and TV grounded (T-HLG)
    - TV to ground with HV and LV grounded (T-HLG)
    - All windings connected together to ground (HLT-G)

NOTE: Windings may be called by a different name than those given above but the above pattern should be used.

1.3. Check Alarm Circuits

- Fault pressure relay trip settings and outputs
- Pressure relief device
- Top oil temperature gauge indications
- Winding temperature gauge indications
- Gas detector relay

1.4. Test Fan Circuits for Continuity and Voltage

1.5. Check Heat Exchangers

If three phase motors are used and rotated the wrong way, reverse any two main winding wire connections at the motor circuit breaker in the main control cabinet.

NOTE: Copies of every test made on a transformer from time of arrival to present location should be included with the customer's permanent file.

1.6. Check the Following before Energizing

- Check the transformer ground.
- Check the feeder cables bus for proper connection to transformer terminals. There should be no strain on the porcelain insulators.
- Check insulating oil for proper level in all bushings and compartments.
- Check opening and joints for proper sealing.
- Check pressure relief device for proper installation.
- Check the valve from the conservator to the main tank. The valve should be in the open position.
- Check all winding neutrals. They should be properly grounded.
- Check the tightness of the packing nut on the de-energized tap charger handle.

1.6. Check the Following before Energizing
(continued)

- Check radiator valve stem packing nuts and tighten as required. Each valve may require 1/3 to 1/2 turn on the packing nut.
- All radiator valves and/or pump valves should be open and bolted.
- Check lightning arresters for proper installation in accordance with specifications.
- Check transformer finish for scratches. Any damage to the transformer finish during installation should be touched up with paint provided.
- Check relay protection, CTs, and relays for proper connections and operation.
- Fan motor drain holes should be open.
- Check terminal connection in control cabinet for tightness. Check to see that there are no loose connections.
- Check conservator tank breather for proper operation. The dehydrating material should be dark blue.
- All temporary busing safety grounds should be removed.
- The gas detector relay should be bled.
- Heaters in the control cabinets should be energized.
- Check that the shorting straps on winding temperature indicator (WTI) CT terminal block and line drop compensation (LDC) CT terminal block are removed. Check that shorting straps are removed from all other CTs that have loads connected.

WARNING: High voltages may develop across open circuit secondary terminals of CTs when energized. Shorting straps must be in place across the full CT winding for all CTs not connected to low impedance loads to prevent possible personnel hazard and damage to the CT and other equipment. All CT secondary circuits must be grounded, either in the transformer control cabinet or at the load, whether or not the CT is in use.

- All drag hands on alarm gauges and the LTC position indicator should be reset.
- Check lightning arresters on dual voltage units for proper connections.
- All personnel should be clear of the transformer.
- Valve between tank and pressure vacuum regulator should be open.
- Check for approximately 3 lbs pressure on sealed tank units.
- All temporary shipping plugs, etc. should have been removed during installation. Typically these are painted either red or yellow, such as breather plugs in the LTC housing.

1.7. Energizing the Transformer

- Apply full voltage and allow the transformer to operate for at least one hour without load. Listen for unfamiliar noises. Check for excessive vibrations.
- Keep the transformer under observation for the first few hours. Watch gauges to see that specified limits are not exceeded.
- After several days of operation, check for any oil leaks that may have developed after energizing.
- Record the time from first energization.
- Check metering or correct inputs and outputs.
- Check relays for proper inputs and outputs.

1.8. Renewal Parts

Should a transformer be damaged and new parts needed, contact the manufacturer, giving full nameplate information and a description of the part required. If the proper name of the part is in doubt, a simple sketch will expedite prompt shipment to you.

1.9. Maintenance

1.9.1. Periodic Inspection

- External: Check the condition of the paint and finish periodically, especially when the transformer is exposed to inclement atmospheric conditions. If weathering takes place, clean the tank thoroughly and re-paint with an ANSI-approved paint. Wipe off any insulating fluid that might have spilled on surface. Occasionally inspect and tighten all bolted joints and check for leaks.
- Regularly inspect all gauges. The fluid level must remain normal, considering the effects of temperature differences. Refill when samples have been taken. Prolonged periods of zero pressure could indicate a gas leak and should be checked. The fluid temperature should not rise higher than the design value on the name plate after including the effects of ambient temperature. Check blanket nitrogen pressure and bottle pressure.
- Fluid samples should be taken periodically and analyzed as indicated under “Sampling”. It is recommended that you keep a log of the test values to determine when reconditioning or replenishing service is required.

1.9.2. Sampling Insulating Fluid

NOTE: A sample of fluid should be taken when the unit is warmer than the surrounding air to avoid condensation of moisture on the fluid. Fluid samples must be drawn from the sampling valve located at the bottom of the transformer tank.

- A clean and dry bottle is required. Rinse bottle three times with the fluid being sampled. Make sure fluid being sampled is representative of fluid in the unit.
- Containers used for sampling fluid should be large-mouth glass bottles.
- Test samples should be taken only after the fluid has settled for some time, varying from eight hours for a barrel to several days for a larger transformer. Cold insulating fluid is much slower in settling. Fluid samples for the transformer should be taken from the sampling valve at the bottom of the tank.
- When sampling, a metal or non-rubber hose must be used because oil dissolves the sulfur found in rubber and will prove harmful to the conductor material in the transformer. When drawing samples from the bottom of the transformer or large tank, sufficient fluid must first be drawn off to ensure that the sample will be from the bottom of the tank, and not the fluid stored in the sampling pipe.

1.9.3. Testing Insulating Fluid

For testing the dielectric strength of insulating fluids, follow the technique as specified by the American Society for Testing Material in the method entitled, "*The Standard Method for Testing Electrical Insulating Oils",* D-877.

If, at any time, the dielectric strength of the fluid drops below 26 kV, it should be filtered until it tests at 26 kV or better.

1.9.4. Filtering Insulating Fluid

Mineral fluid can be filtered by means of a filter press. The filter press is effective for the removal of all types of foreign matter, including finely divided carbon and small amounts of moisture. The purifier equipment consists of a specifically proportioned filter press, a positive volume gear pump, driving motor, combined drip pan and mixing tank, necessary piping, valves, strainer, gauges and a drying oven.

The filtering procedure that will ensure the best result is to draw the insulating fluid from one tank, through the filter press, and into a clean tank. Where this method is not practical, a circulation method is recommended. Fluid is drawn from the bottom of a tank, passed through the purifier and discarded at the top of the tank.

Filtration should be continued until the dielectric test of the insulating fluid is 26 kV or better.

1.10. Spare Parts and Services

Keep one set of gaskets for the hand hole and any gasket type bushings used. Other renewal parts may be ordered through the manufacturer. When ordering, give a complete description of the part or problem and give the complete serial number as listed on the nameplate.

1.11. Applicable Standards

- NEMA Publication TR-98 (Latest Issue): "*Guide for Loading Fluid Immersed Power Transformers with 65°C Average Winding Rise*".
- ANSI Publication C57.93 (Latest Issue): "*Guide for Installation and Maintenance of Fluid Immersed Transformers*".
- IEEE Publication 64 (Latest Issue): "*Guide for Acceptance and Maintenance of Insulating Fluid in Equipment*".
- ASTM Specification D-877: "*The Standard Method of Testing Electrical Insulating Fluids*".

2. Surge Arrestors

Surge arrestor provide over voltage protection for dielectric components. If arrestors are not functioning properly, the components they are designed to protect will likely fail prematurely. During commissioning, surge arrestors on the high and low side transformer and the beginning, midpoint, and end of cable systems typically have the following tests and inspections performed:

- Verify that “station class” arrestors are installed at all overhead-to-underground transitions.
- Verify nameplate ratings against owner’s specification.
- Insulation resistance test and/or power factor testing should result in similar test results between similar units.
- Test for low impedance path to ground grid with no sharp turns.
- Check the lead length to assure that is it not longer than the manufacturer’s requirement. Long lead lengths cause the device to malfunction.

Surge arrestors are also used at cable system cross-bond points. These arrestors should be inspected and tested according to the manufacturer’s recommendations. Lead length should be less than a few feet.

Maintenance of arrestors is recommended. Arrestors should be visually inspected annually. Electrical tests should be performed every 2 years, after system failures, or per the manufacturer’s recommendation.

3. Active and Passive Components

Capacitors, reactors, VAR compensators, and energy storage systems need to be inspected, maintained, and monitored on a frequent basis. Real-time monitoring is recommended for these critical assets. See the Appendix for maintenance intervals.

4. Relays

The following describes a recommended approach to relay testing:

- Perform comprehensive commissioning testing at the time of installation. Use thorough checklists, simulations, laboratory testing, and/or field checks to verify the performance of the protection system, including inputs, outputs, and settings.
- Monitor the relay self-test alarm contact in real time via supervisory control and data acquisition (SCADA) or other monitoring system. If an alarm contact asserts, take immediate steps to repair, replace, or take corrective action for the alarmed relay.

4. Relays
(continued)

- Monitor potential relay failures not detected by self-tests. Specifically, these are logic inputs, contact outputs, and analog (voltage and current) inputs. Use continuous check of inputs, e.g. loss-of-potential logic, when available. If a secondary relay system is in place, compare the metering values between the primary and secondary systems.

5. Batteries and Backup Power

5.1. Battery Systems

Each battery system should be maintained and operated as guided by industry practice and manufacturer's recommendations. The following is generally accepted information for the major types of batteries:

5.1.1. Vented Lead

Vented lead-acid cells, known also as wet or flooded cells, make up the majority of DC battery cells in service at sites. The internal lead and lead-sulfate (Pb and PbSO4) plates are formed with small amounts of antimony, tin, calcium, or selenium alloyed in the plate material to add strength and simplify manufacture. The alloying element has a great effect on the life of the batteries. As water use can be high, electrolyte levels have to be monitored and adjusted as necessary. Equalization charges are necessary for some designs. Fifteen to 20 year life is normal if the cells are well-maintained; however, amp-hour capacity will drop to 80% towards end of life.

- **Vented Lead-acid Antimony:** Vented lead-acid antimony batteries have a nominal specific gravity of 1.210-1.220. Cells have an average float charge of 2.19±0.04 DC volts per cell.
- **Vented Lead-acid Calcium:** Vented lead-acid calcium batteries have a nominal specific gravity of 1.210-1.220. Cells have an average float charge of 2.21±0.04 DC volts per cell.
- **Vented Lead-acid Selenium:** Vented lead-acid selenium batteries have a nominal specific gravity of 1.235-1.250. Cells have an average float charge of 2.20 DC volts per cell, but not more than 2.25 DC volts per cell.

5.1.1. Vented Lead
(continued)

Vented lead-acid Plante cell have lead plates which are grooved to increase their surface area. Special fabrication techniques make this a mechanically and electrically durable battery, but also very costly. Twenty-five year life expectancy is warranted, as is the ability to deliver 100% designed capacity over the full useful life. Watering requirements are minimal and the battery can operate at higher temperatures than non-Plante designs.

- **Vented Lead-acid Plante:** vented lead-acid Plante batteries have a nominal specific gravity of 1.210-1.220. Cells have an average float charge of 2.24±0.01 DC volts per cell at 20-25°C. A voltage of 2.25 DC volts per cell will ensure full capacity at all times with low water loss and will fully recharge the battery after a discharge.

5.1.2. Valve Regulated Lead-acid (Gel Cells)

Valve regulated lead-acid batteries, or gel cells, are often referred to as maintenance free, but this is a misnomer. These batteries remain under constant pressure (1-4 psi), which helps the hydrogen and oxygen gases generated during charging turn back into water. As these cell casings are sealed and non-vented, excessive gas pressure build up is prevented with the installation of a regulating valve. Battery room ventilation requirements are minimal with these sealed cells. These batteries are approximately 60% of the cost of a vented lead–acid cell but can last 20 years if well maintained.

The two most common types are the gel and absorbed glass mat (AGM).

- **Gel Batteries:** gel batteries have a gelling agent (fumed silica) in the electrolyte which immobilizes it in the cell.
- **AGM Batteries:** AGM batteries have a thin fiberglass that holds the electrolyte in place like a sponge. This style battery is preferred over the gel cells.

It is important not to overcharge these batteries. Keeping the temperature of the negative post of the battery within spec will help prevent excessive gassing and thermal runaway. Excessive battery charger AC ripple can damage these cells. While electrolyte levels cannot be monitored as with a vented lead-acid battery, regular testing (impedance/conductance) can detect a dry-out con-

5.1.3. Valve Regulated Lead-acid (VRLA) Batteries

Valve regulated lead-acid (VRLA) batteries have a nominal specific gravity of 1.300. Cells have an average float charge at 2.25-2.30 volts per cell at 20-25°C. VRLA batteries with a nominal specific gravity of 1.250 are to be kept on a float charge of 2.20-2.25 DC volts per cell at 20-25ºC. As the room temperature changes, it is necessary to adjust the float voltage proportionally: 2.33-2.36 volts @ 0°C and 2.21-2.24 volts @ 40°C. Increasing the charge voltage to 2.40 volts per cell can reduce charge time of a discharged battery; however, the charge must be monitored and terminated when the charge current decreases to a constant value.

NOTE: Refer to the specific battery manufacturer's recommended float charging voltage for proper float voltage levels.

5.2. Recommended Inspections of Batteries and Backup Power

5.2.1. Physical Inspection

Battery cell casings/jars are to be kept clean and dry. Necessary precautions are to be taken to prevent the intrusion of foreign matter into the cells. Cell caps and flame arrestors are to be in place. All cell connections should be kept tight and free from corrosion.

5.2.2. Room and Cell Temperature

Temperature affects batteries and may alter the set point of the charger voltage. When taking any measurements, always record the temperature of the battery room. As battery cell temperatures drop, so does stored energy capacity. Higher temperatures increase capacity but lower life expectancy. EPRI recommends a battery room temperature range between 60°F (15.5ºC) and 90°F (32.2ºC), with an average of 77°F (25ºC).

5.2.3. Battery Room Ventilation

Battery rooms should be adequately ventilated and exhausted outside the room to an open or outside area. Hydrogen gas concentrations in atmosphere greater than 4% are considered potentially explosive. Room air flow should be sufficient enough to prevent pockets of hydrogen from concentrating near the ceiling.

5.2.3. Battery Room Ventilation
(continued)

NOTE: If the ventilation system is out of service and work needs to be performed in the battery room, the area should be treated as hazardous, both for its oxygen deficiency and for its potentially explosive atmosphere. The room should be ventilated with portable/temporary air movers before proceeding with any work.

5.2.4. Electrolyte Levels

Only battery manufacturer's approved water (distilled or demineralized) shall be used to maintain the electrolyte level in the cell between the marked liquid level lines. Do not overfill the cell. Acid should never be added to or removed from a cell without specific instructions from the manufacturer.

5.2.5. Float Voltage

A battery's float voltage has an effect on the stored amp-hour capacity of the battery. In general, as the float voltage is reduced, so is the stored amp-hour capacity. However, maintaining a higher than suggested float voltage may cause an accelerated decrease of cell electrolyte levels as water is lost.

5.2.6. Inter-cell Connection Resistance

For a battery's inter-cell connection resistance, the measurements for each connection should be obtained and recorded to establish baseline data. A connection should be disassembled, cleaned, reassembled, re-torqued, and re-tested if any connection is greater than 20% above the average resistance or greater than 5 micro-ohms above average (if 5 > 20%).

The re-tested connection measurements should be used in the baseline dataset for future comparison and trending.

During routine testing of inter-cell resistances, an increase of 20% from the recorded baseline readings, for that individual connection, not the battery average, is cause for corrective action.

Sites shall maintain baseline resistance data, as applicable to their battery configuration, for use in determining SAT (less than 20% over baseline) or UNSAT (greater than 20% over baseline) results as measured during routine testing. This individual connection data shall be updated as necessary when connection work changes baseline data.

5.2.6. Inter-cell Connection Resistance
(continued)

NOTE: Refer to IEEE Std. 450, Annex F, "*Methods for Performing Resistance Measurements*". Refer to IEEE Std. 450, Annex D.2 for discussion of baseline data.

5.2.7. Internal Impedance/Conductance Testing

Internal resistive (conductive) measurements, or BITE (battery impedance test evaluation), can be used to evaluate the electrochemical characteristics of battery cells. The measurements can provide indication of individual cell problems and a degraded ability to provide emergency DC power when required.

Baseline data should be recorded in the first six months, if possible, of placing a battery in service. The record datasheet should note the date of battery (bank or individual) installation and the date when baseline data was recorded. Note that baseline data will vary depending on manufacturer, battery model, amp-hour capacity, and the measuring equipment used.

Testing should be performed under similar conditions, such as cell temperature, float voltage, and charging current. Results will vary with the various models and styles of test equipment, so it is preferable to always use the same equipment.

Significant changes (greater than 100% for impedance, greater than 50% for conductance) from baseline values should be investigated. Over the useful life of a battery, the average cell impedance will rise. Batteries whose impedance values differ from the current testing year bank average by ±20% should be considered for individual load test, equalize charging, or replacement.

NOTE: Refer to IEEE Std. 450, Annex J for further information.

5.2.8. Negative Terminal Temperature (VRLA Batteries Only)

Negative terminal temperature should be less than 3°C (5°F) above room/area ambient temperature. This specification is linked to the requirement that battery charger current and voltage ripple be limited to the values listed below. Ripple above those limits drives internal chemical reactions at the negative post and will release heat into the cell.

5.2.9. Charger AC Ripple Voltage/Current (VRLA Batteries Only)

- Max Voltage ripple: 0.5% of DC float voltage
- Max Current ripple: 5 A per 100 amp-hr rating of battery

6. Generator Lead Line

CAUTION: Extreme caution should be used with inspecting transmission line systems.

6.1. Inspecting the Generator Lead Line.

6.1.1. The interconnect line will be inspected semi-annually for structural integrity and as part of the vegetation management program.

6.1.2. The inspection will be a ground-based inspection conducted by a qualified technician with a check list of items to inspect.

6.1.3. Detailed structural inspections will be conducted on an “as needed” basis.

6.1.4. Personnel assigned to conduct interconnect line inspections will be trained on proper inspection techniques, actions to take when vegetation conditions present an imminent threat of a transmission line outage, the requirements of this procedure, and the requirements for working in the vicinity of energized transmission lines. Documentation of this training should be maintained on-site for a minimum of 5 years.

6.1.5. Any vegetation condition that presents an imminent threat of a transmission line outage will require immediate notification to the owner and an entry recorded in the facility log. An action plan, that may require switching the line out of service, will be implemented until the threat is removed.

6.1.6. Structural components will be visually inspected, utilizing binoculars where needed. If available, during periods of high generation loading, the inspection will include the use of an IR camera to identify high resistance connections. Discrepancies noted during the IR camera survey will be recorded and images will be archived for historical trending.

6.1.7. Visual inspections shall be made to ensure no erosion is present from washouts and/or other means that could result in unstable structural conditions.

6.1.8. Significant discrepancies will be noted with follow up actions itemized. It is recommended that high resolution photographs accompany any discrepancy report.

6.1.9. The inspection results will be reviewed and signed by the owner.

6.1.10. The owner, or designee, is responsible for maintaining the status and remediation of all discrepancies.

6.2. Transmission Vegetation Management Program (TVMP)

6.2.1. The objective of the TVMP is to improve the reliability of the interconnect line by minimizing outages caused by vegetation on or adjacent to the interconnect right of way.

6.2.2. TVMP inspections will be conducted at the same time as the structural inspections.

6.2.3. “Clearance 1” distance shall be a minimum of 50 feet on either side of transmission line centerline. Within those boundaries, all vegetation will be cut to less than 1 foot high. Danger trees beyond 50 feet will be adequately trimmed or removed. Vegetation management need only be conducted when routine inspections identify vegetation that has encroached or violated the “clearance 2” distance.

6.2.4. “Clearance 2” distance shall be a minimum of 25 feet radial clearance between vegetation and all phase conductors under all rated electrical operating conditions. This distance is in excess of the IEEE recommended MAID distance of 4.4 feet, corrected for altitude (ref. IEEE Standard 516-2009, Annex D, Table D.9, where T = 3.0).

6.2.5. Inspection results identifying vegetation that has encroached upon the “clearance 2” distance will require vegetation management work to establish all vegetation back to “clearance 1” distances. Vegetation management work should be completed within 60 days of identifying encroachment beyond the “clearance 2” distance. This time requirement is based upon local conditions.

6.2.6. In the event that there are restrictions in attaining the "clearance 1" distance, monthly vegetation management work will be conducted to maintain all vegetation at the "clearance 2" distance. This monthly vegetation management requirement will stay in place until all restrictions are removed and the "clearance 1" distance is re-established.

6.2.7. Vegetation management work will only be conducted by contractors trained and qualified to perform vegetation management work in the vicinity of live transmission lines.

6.2.8. The vegetation management contractor will develop and submit a work plan that:

- Lists all areas noted during the interconnect line inspection where "clearance 2" distance violations were identified
- Specifies the scope of work to be completed including the vegetation management methods to be utilized
- Lists all chemicals planned for use with MSDS sheets attached
- Provides an itemized check list for each area of work with spots for completion signatures by contractor personnel after work quality is accepted by site managers
- Provides documentation that all contractor personnel have been trained on the applicable sections of this procedure and the actions to take upon discovering any vegetation condition that presents an imminent threat of a transmission line outage

The completed work plan will be retained on site for a minimum of 5 years.

6.2.9. Vegetation management work may utilize manual clearing, mechanical clearing, herbicide treatment, or other industry approved methods, as needed, to establish the required distance of "clearance 1". Address any discrepancies identified during the interconnect line inspection.

6.2.10. Vegetation management work plans will comply with all local, state, and federal requirements.

6.2.11. Vegetation management work plans will require review and approval of the environmental program manager prior to commencement of work.

6.2.12. The owner or designee will ensure compliance with all lease and easement requirements prior to commencing any vegetation management work.

7. Secondary Cable Systems

7.1. In some cases, secondary cables are utilized in substations. The secondary cable insulation rating will range from 600 V to 2000 V depending on the cable design and the wind turbine generator (WTG) type. Typical installations will require multiple conductors per phase. Conductors should be properly labeled with phasing tape or colored cable jackets. After installation and prior to termination to the transformer and controller, a DC insulation resistance test ("megger") is typically performed. The test voltage is dependent on the insulation value, but is usually in the range of within 500 V to 2,500 V. The intent of the installation tests are to:

- Ensure that the insulation was not shorted during the installation process. A low voltage insulation resistance measurement of less than 100 megohm may indicate a problem.
- Verify the cable phasing from one end to the other.

Generally, secondary cable systems are not re-tested as a maintenance practice unless there is reason to suspect a problem. An annual infrared inspection of the terminals is recommended, especially on cables deemed critical.

8. Fiber Optic Cable Systems

Upon installation and termination of the fiber optic cables from each WTG, tests are performed to ensure the quality of the fiber optic cable and terminations. Typically one of the following two tests are performed: attenuation (dB) loss testing or optical time domain reflectometer (OTDR) testing

Since the network is constantly used for data transmission, it is, in effect, constantly monitored. If there is a network problem, one of the tests above can generally help diagnose the problem. Other than a visual inspection of the connections, periodic maintenance is generally necessary.

9. Medium Voltage Cable Systems

Medium voltage cable systems can be found as a part of the substation electrical system. During commissioning, field tests range from legacy methods, such as insulation resistance and withstand methods, which are only effective at detecting gross shorts (cable system failures), to sophisticated, predictive partial discharge (PD) tests, which detect and locate gross and subtle insulation defects and provide a baseline for future use. The standardized electrical test requirement at the factory for all completed solid dielectric shielded cable insulation system components, including the cable, joints, and terminations, is a partial discharge test performed during a 50 Hz or 60Hz over voltage. Ideally, a partial discharge test comparable with the factory test can be repeated on installed cable systems to ensure that they still meet these requirements. If this type of test is not available or deemed impractical for a specific application, a list of alternative tests can be found in the IEEE 400 guide document.

Ideally, during commissioning the following steps are completed on a cable system and a baseline is established:

- Visual inspection for physical damage, such as bends at less-than-minimum bending radius, phase identification, fireproofing, proper shield grounding, cable supports and termination connections, required size and rating per design drawings, and proper separation of power, control, instrumentation, and emergency circuits.
- Conductor phasing test
- Resistance of neutral wires and tapes and conductor resistance/ continuity
- Off-line 50 Hz or 60 Hz PD test on each individual span of cable from termination to termination point. This test can provide a profile of the cable system which is comparable to factory standards listed below.
- DC Insulation resistance test (“megger test”) or very low frequency AC test, at the operation voltage or less, on the entire cable system. This test is not intended to detect defects which may fail in the near future but, rather, to detect pre-existing shorts.
- Infrared test of the accessories (terminations and accessible splices) under high current condition.

9. Medium Voltage Cable Systems
(continued)

Table A: Cable System Insulation Test Standards.

Cable Component	Thresholds
IEEE 48 Terminations	No PD >5pC up to 1.5Uo
IEEE 404 Joints	No PD >5pC up to 1.5Uo
IEEE 386 Separable Connectors	No PD >3pC up to 1.3Uo
ICEA S-94-649 MV Cable	No PD >5pC up to 2Uo*

*Actually 200 V/mil in factory. Field tests are performed to a maximum voltage value equal to the level of system over voltage protection which is typically 2 times the operating voltage for 35 kV systems (line to ground, 1.0 Uo).

9.1. After a failure

A DC insulation resistance test at an operating voltage or less, i.e. 10 kV or 20 kV for a 35kV system, is recommend after any failure event to confirm the phase of the fault and to confirm that there is not a second fault before re-energizing. Arc reflection fault location technology should be used with a minimum number of pulses to determine the location of the fault. To confirm dielectric integrity of the system after repair, an off-line 50 Hz or 60 Hz PD test is recommended. In some cases, relays can provide some information about the fault.

9.1.1. Cable Fault Location Equipment/Thumpers

Fault locating methods use fault indicators ("thumpers"), radars, acoustic detectors, or combinations of this equipment. Research indicates that subjecting cable systems to unnecessary surges reduces their remaining life. The industry has developed less evasive fault locating methods that reduce the stress on cable insulation systems. The general approach is to reduce the amount of thumping necessary to locate a fault while simultaneously reducing the voltages required to perform the task.

9.2. Periodic Testing

Comparative infrared testing is recommend annually to check the condition of the mechanical connection of cable system joints and terminations. Off-line 50 Hz or 60 Hz PD testing is recommended every 5 years.

Appendix of Maintenance Checklist and Intervals

Table B: Substation Inspection and Maintenance Intervals Based on a 6-year Maintenance Cycle

Recommended Substation Maintenance Tasks and Intervals	Installation & Commissioning	5W (Monthly)	3M (Quarterly)	1Y (Yearly)	3 Years	6 Years	12 Years	24 Years
Switchgear								
Inspect, clean, exercise	X			X				
Grounding Transformers								
Testing should be similar to main power transformers where applicable.	X			X				
Relay Panels								
Physically inspect lockout relays for mechanical and electrical integrity.	X				X			
Inspect panel wiring.	X				X			
Check as-found settings against past known settings.	X				X			
Perform a physical inspection of relay.	X				X			
Verify relay settings to RSO/relay database information.	X				X			
Log any settings changes for testing.	X				X			
Check and record as-left settings values.	X				X			
Lamp and megger all CT circuits.	X				X			
Measure and record all three phase potential and currents inputs.	X				X			
Perform all control circuit operations including trip checks.	X				X			
Initiate communications devices.	X				X			
Check all external trips to the circuit breaker under test.	X				X			
Check any digital fault recorder points monitoring the relay package.	X				X			
Verify relay alarms.	X				X			
Replace DC and low voltage potential circuit fuses on transmission protection circuits.	X				X			
Check power supply lights, alarms, targets, etc. on relays. Record results.	X	X						

Appendix of Maintenance Checklist and Intervals

Table B: Substation Inspection and Maintenance Intervals Based on a 6-year Maintenance Cycle (continued)

Recommended Substation Maintenance Tasks and Intervals	**Installation & Commissioning**	**5W (Monthly)**	**3M (Quarterly)**	**1Y (Yearly)**	**3 Years**	**6 Years**	**12 Years**	**24 Years**
Communications Panels								
Inspect panel wiring.	X					X		
Verify any auto and/or logic.	X					X		
Perform all control circuit operations including trip checks.	X					X		
Verify correct operation of check back device or other auto test device.	X					X		
Verify operation and reset of communications alarms.	X					X		
Check power supply lights, alarms, status, etc. on comm. equipment where applicable.	X	X						
Substation Grounding Systems								
Visual inspection (equipment, fence, gates)	X	X						
Motor Operated Disconnects								
Visual inspection	X	X						
Thermography	X			X				
Operate, inspect, lubricate	X				X			
Contact resistance (ductor) test	X				X			
Blade and hinge assembly maintenance	X						X	
Check cabinet heaters.	X	X						

Appendix of Maintenance Checklist and Intervals

Table B: Substation Inspection and Maintenance Intervals Based on a 6-year Maintenance Cycle (continued)

Recommended Substation Maintenance Tasks and Intervals	Installation & Commis-sioning	5W (Monthly)	3M (Quarterly)	1Y (Yearly)	3 Years	6 Years	12 Years	24 Years
Circuit Breakers - SF_6								
Check indicating lamps (red and green).	X	X						
Visual inspection	X	X						
Thermography	X			X				
Contact resistance (ductor) test	X				X			
Profile breaker operation.	X				X			
Power factor test	X				X			
Travel test	X				X			
SF_6 moisture test	X			X				
Exercise mechanism	X				X			
Mechanism lubrication and maintenance	X				X			
Pressurized vessel inspection	X				X			
Relief valve replacement	X				X			
Internal inspection	X						X	
Mechanism refurbishment								X
Check control cabinet heaters.	X	X						
Check SF_6 tank heaters.	X	X						
Check gauges and pressure switches.	X				X			
Functional alarm test	X				X			
Substation Bus								
Visual inspection	X	X						
Thermography	X			X				
Verify torque of bolted connections.	X					X		
Substation Foundations								
Visual inspection	X	X						

Appendix of Maintenance Checklist and Intervals

Table B: Substation Inspection and Maintenance Intervals Based on a 6-year Maintenance Cycle (continued)

Recommended Substation Maintenance Tasks and Intervals	Installation & Commissioning	5W (Monthly)	3M (Quarterly)	1Y (Yearly)	3 Years	6 Years	12 Years	24 Years
Substation Power Transformers								
Monitor nitrogen pressure (blanket and bottle).	X	X						
Monitor oil level.	X	X						
Monitor oil temperatures (top oil and LTC).	X	X						
Monitor oil flow indicator.	X	X						
Monitor winding temperature.	X	X						
Monitor gas accumulator as applicable.	X	X						
Oil dissolved gas analysis	X		X					
Oil quality test	X		X					
Thermography	X		X					
Power factor test	X				X			
Low voltage excitation test	X				X			
Winding resistance (TTR on all taps)	X				X			
Frequency response analysis	X				X			
Maintenance inspection	X				X			
Power wash heat exchangers.	X				X			
Check cabinet heaters.	X	X						
Check bushing oil level.	X	X						
Visual inspection	X	X						
Functional test, cooling system, alternate lead/lag coolers	X	X						
Record and reset top oil temperature.	X	X						
Record and reset top winding temperature range.	X	X						

Appendix of Maintenance Checklist and Intervals

Additional notes to maintenance tasks and intervals: many of these tasks can be minimized or eliminated if real-time monitoring is provided for these assets.

Table B: Substation Inspection and Maintenance Intervals Based on a 6-year Maintenance Cycle (continued)

Recommended Substation Maintenance Tasks and Intervals	Installation & Commissioning	5W (Monthly)	3M (Quarterly)	1Y (Yearly)	3 Years	6 Years	12 Years	24 Years
Substation Power Transformers (continued)								
Functional test LTC, run through 'neutral'.	X	X						
Functional alarm test (aux relay installations)	X		X					
Functional alarm test (direct wired)	X				X			
Inspect bushing potential tap.	X				X			
Check and verify gauges and alarms.	X				X			
Test sudden pressure relay.	X				X			
Check automated aux power throw-over switch.	X				X			
Transformer turns ratio test	X				X			
Substation Yard								
Visual inspection	X	X						
Oil/water separator check	X			X				
Station summarization (cooling)	X			X				
Station winterization (heating)	X			X				
Surge Arrestors								
Thermography	X			X				
Power factor test	X				X			
Visual inspection	X	X						
Detailed visual report	X				X			
MV Cable								
Thermography terminations (high load)	X			X				
Off-line 50/60 Hz PD test	X					X		
Visual inspection	X			X				
LV Cable								
Thermography terminations (high load)	X			X				
Insulation resistance	X							

Transmission Line
These tasks should be done at the time of original installation and commissioning and then repeated at 1 year and every 3 years. Thermography should be done quarterly.

Table C: Transmission Line Tasks

Transmission Pole and Frame Structure Inspections	**Installation & Commissioning**	**3M (Quarterly)**	**1Y (Yearly)**	**3 Years**	**6 Years**	**12 Years**	**24 Years**
Pole identification plates are present and fastened securely to the structure	X				X	X	X
Cross arm inspection: rainwater entrapment and moisture damage at connection points and hardware fastening points	X				X	X	X
Oil coating inspection. Verify the wood surface is adequately soaked with oil.	X			X	X	X	X
Frame does not lean or list outside of intended structural design	X			X	X	X	X
Insulators and transmission cable: strong ties securely fasten cable to insulator glass	X				X	X	X
Insulators and transmission cable: insulators are clean with no evidence of arcing	X				X	X	X
Insulators and transmission cable: insulators are not cracked	X				X	X	X
Insulators and transmission cable: insulators are mounted perpendicular to the frame/ structure and cable is not causing undue stress at the attachment point	X				X	X	X
Use clamp-on ammeter to identify any AC drain current flowing into the ground circuit.	X				X	X	X
Torque Checks and Verification							
Re-torque hardware at cross arm joints.	X				X	X	X
Re-torque hardware at all jointed connections of the frame.	X				X	X	X
Re-torque hardware at all arrestor and insulator attachment points.	X				X	X	X
Re-torque hardware at all auxiliary hardware attachment points, i.e. fiber.	X				X	X	X
Re-torque hardware at all guy wiring cable crimp hardware.	X				X	X	X

Transmission Line

These tasks should be done at the time of original installation and commissioning and then repeated at 1 year and every 3 years. Thermography should be done quarterly.

Table C: Transmission Line Tasks (continued)

Transmission Pole and Frame Structure Inspections	Installation & Commissioning	3M (Quarterly)	1Y (Yearly)	3 Years	6 Years	12 Years	24 Years
Arrestors							
Megger all arrestors on the transmission line circuit. Provide insulation results in final report.	X				X	X	X
Inspect ground connection points on arrestors and ensure they are secure.	X				X	X	X
Inspect arrestor insulators for signs or arcing or tracking to ground.	X				X	X	X
Verify mounting hardware is present.	X				X	X	X
Riser Poles							
If applicable, inspect all disconnects for proper seating and no evidence of overheating or arcing at seated position.	X				X	X	X
Inspect cable for chafe marks at the point where cable exits the riser conduit stubs.	X				X	X	X
Verify mounting hardware of conduit riser stubs are all present and secure.	X				X	X	X
Verify conduit stubs are sealed. Foam seal if not sealed.	X				X	X	X
Torque check cable terminations.	X				X	X	X
Inspect cable terminations for signs of overheating, arcing, etc.	X				X	X	X
Inspect additionally mounted hardware and reenforcement for signs of looseness.	X				X	X	X
T-Line and Fiber Inspections							
Inspect all splice points for fraying, slipping, or failure.	X				X	X	X
Cable and fiber sag is uniform as compared phase to phase	X				X	X	X
Cable and fiber sag is uniform from pole to pole	X				X	X	X
Excess fiber coils are secured and not loose at coil locations	X				X	X	X

Transmission Line
These tasks should be done at the time of original installation and commissioning and then repeated at 1 year and every 3 years. Thermography should be done quarterly.

Table C: Transmission Line Tasks (continued)

Transmission Pole and Frame Structure Inspections	Installation & Commissioning	3M (Quarterly)	1Y (Yearly)	3 Years	6 Years	12 Years	24 Years
Guy Wiring and Structural Re-enforcements							
Check tension on all guy wires. Tighten any found to be loose.	X				X	X	X
Check that fastening hardware is present and torque marked.	X				X	X	X
Check that guy wire marker sleeves are present and in good repair.	X				X	X	X
Torque check all fastening hardware.	X				X	X	X
Galvanized Frame Structures (If Applicable)							
Inspect protective coating/galvanized coating. Look for rust spots.	X				X	X	X
Perform inspections at welded joint locations. Look for cracks or rust in welded joints.	X				X	X	X
Check that ground connection hardware is present and secure.	X				X	X	X
Inspect structure foundations for signs of stress cracking or water intrusion.	X				X	X	X
Vegetation Management/Inspection							
Fire boundary at the dirt/base exists and is acceptable	X				X	X	X
Overhead vegetation is clear of poles, lines, etc. Vegetation boundary allowance, adjacent to cables, incorporates line sag and wind sway	X				X	X	X

Transmission Line
These tasks should be done at the time of original installation and commissioning and then repeated at 1 year and every 3 years. Thermography should be done quarterly.

Table C: Transmission Line Tasks (continued)

Transmission Pole and Frame Structure Inspections	Installation & Commissioning	3M (Quarterly)	1Y (Yearly)	3 Years	6 Years	12 Years	24 Years
Thermography Inspection							
Perform thermographic inspection on all arrestors.	X	X			X	X	X
Perform thermographic inspection on all T-line Terminations.	X	X			X	X	X
Perform thermographic inspection on all disconnects & fusing.	X	X			X	X	X
Perform thermographic inspection on all T-line splices.	X	X			X	X	X
Perform thermographic inspection on all insulators.	X	X			X	X	X
Perform thermographic inspection on all ground wiring and jumpers.	X				X	X	X
Reporting: General							
Prepare report with all deficiencies identified from the above check lists.	X				X	X	X
Identify all deficiencies in the summary portion of the maintenance and inspection report.	X				X	X	X

Transmission Line
These tasks should be done at the time of original installation and commissioning and then repeated at 1 year and every 3 years. Thermography should be done quarterly.

Table C: Transmission Line Tasks (continued)

Transmission Pole and Frame Structure Inspections	Installation & Commissioning	3M (Quarterly)	1Y (Yearly)	3 Years	6 Years	12 Years	24 Years
Reporting: Thermography							
Description of equipment and/or object including phase if required	X	X			X	X	X
Identify criticality of the equipment.	X	X			X	X	X
Date and time of inspection	X	X			X	X	X
Visual photograph adjacent to infrared picture	X	X			X	X	X
Thermograms	X	X			X	X	X
Ambient temperature, wind speeds, and weather conditions	X	X			X	X	X
Thermographer name	X	X			X	X	X
Related operating parameters (equipment loading conditions)	X	X			X	X	X
Probable cause of failure indicated	X	X			X	X	X
Recommendation	X	X			X	X	X
Operational status	X	X			X	X	X
Temperature rise	X	X			X	X	X
Temperature reference	X	X			X	X	X
Related past history of equipment	X	X			X	X	X
Maximum operating temperature of equipment being thermal imaged (generally available on the name plate)	X						
All temperatures reported should be on Celsius scale	X	X			X	X	X
Off-line power frequency PD Test	X				X		
Infrared inspection of terminations and splices (high load)	X				X		

Transmission Line
These tasks should be done at the time of original installation and commissioning and then repeated at 1 year and every 3 years. Thermography should be done quarterly.

Table D: Battery Charger Installation

Battery Charger Installation	**Installation & Commissioning**	**5W (Monthly)**	**3M (Quarterly)**	**1Y (Yearly)**	**3 Years**	**6 Years**	**12 Years**	**24 Years**
Verify charger functions and alarms.	X	X						
Load test	X			X				
Battery								
Visual inspection	X	X						
Battery cell voltage readings	X		X					
Annual battery inspection	X			X				
Internal impedance test	X			X				
Thermography	X			X				

Table E: Static VAR Compensators and Energy Storage

Battery Charger Installation	**Installation & Commissioning**	**5W (Monthly)**	**3M (Quarterly)**	**1Y (Yearly)**	**3 Years**	**6 Years**	**12 Years**	**24 Years**
Inspect, maintain, and monitor.	X	X	X	X	X	X	X	X
Thermographic inspections	X	X	X	X	X	X	X	X
Verify correct operation.	X	X	X	X	X	X	X	X
Capacitor and Reactor Banks								
Inspect, maintain and monitor.	X	X	X	X	X	X	X	X
Thermographic inspections	X	X	X	X	X	X	X	X
Verify correct operation	X	X	X	X	X	X	X	X

Chapter 7 End of Warranty

Operations and Maintenance
Recommended Practices

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